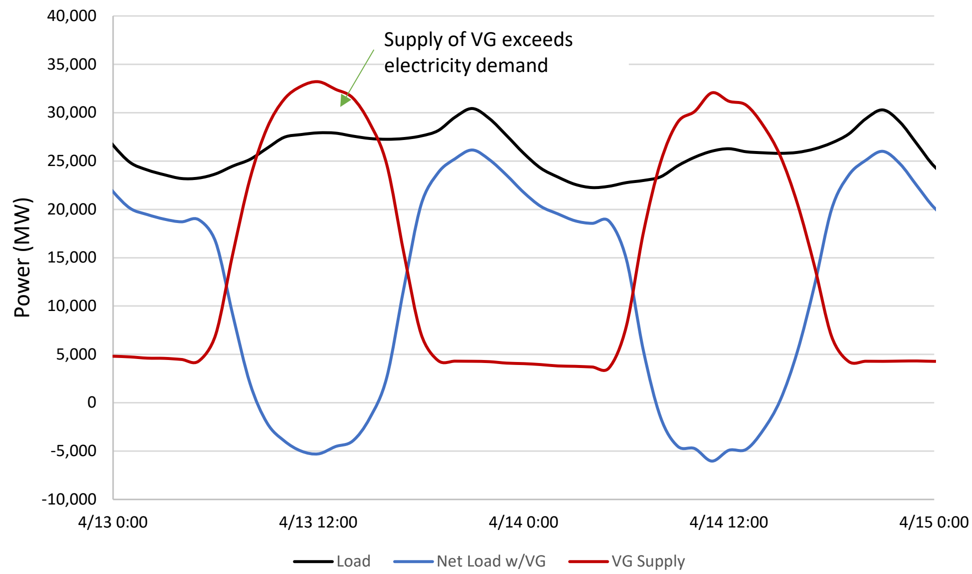
The actual choice between these two options—shorter-duration storage with lower capacity credit or longer-duration storage with full capacity credit—will be driven by many factors, including the value of other services, such as time-shifting. For example, to reduce the net load by 100 MW at the point where the peak net load is 8 hours, we would need 800 MWh of stored energy. We could achieve this by adding a 100-MW device with 8-hours of capacity. Alternatively, we could add a 133-MW device with 6-hours of capacity (meaning the plant would operate at less than full power output when discharging to reduce the peak by 100 MW). Both options provide the same amount of stored energy. For assuming the same storage technology, the 133-MW storage plant would almost certainly cost more than the 100-MW storage plant, as they have the same energy capacity. This additional 33 MW of power-related costs provides no additional capacity-related value. But the additional power capacity might provide additional energy shifting opportunities and thus depending on the value of energy shifting or other value streams, different configurations may be cost-effective.

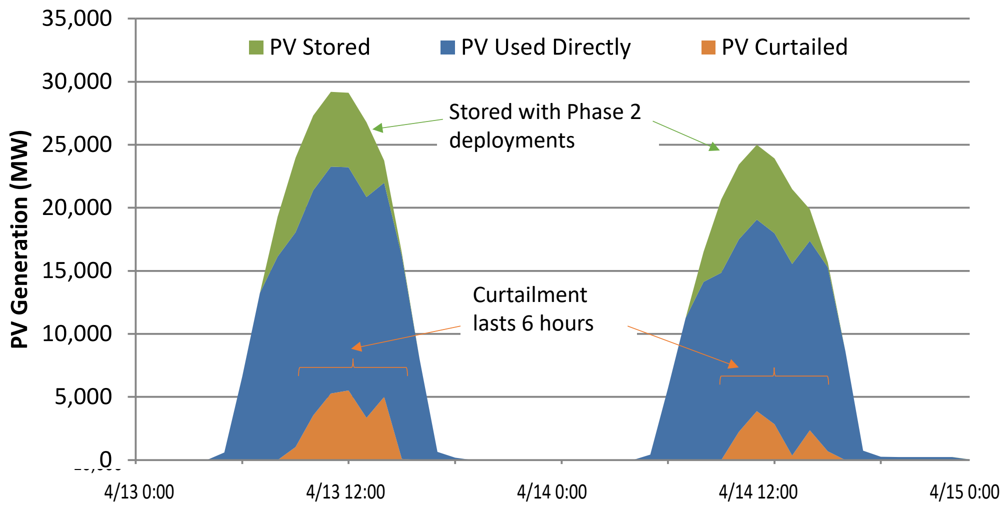
Figure 15 (page 29) illustrates this concept. It shows how storage with a higher power-to-energy ratio (shorter-duration) storage allows for greater capture of curtailed energy. This could result in potentially higher energy shifting value, particularly under scenarios of greater PV deployment, and potentially offset the decline in capacity value. Figure 15a shows the load and VRE supply in the same California scenario as shown in Figure 13, but on two spring days. The large amount of solar energy, combined with system flexibility limits, results in a surplus of solar energy. Figure 15b show how storage deployed for peaking capacity (Phase 2) can absorb much, but not all of this curtailed solar, leaving additional opportunities. If we add the 800 MWh of storage needed to reduce peak demand, we can consider the impact of power capacity and duration on energy shifting value. The residual curtailment on each day lasts for 6 hours, so if we add the lower-cost option (100 MW of 8-hour storage), it can charge at 100 MW for 6 hours and absorb only 600 MWh of curtailment, meaning 200 MWh of storage capacity is unused. Alternatively, the 133 MW of 6-hour storage can charge at full power capacity and can store the full 800 MWh. As a result, the higher power capacity is better aligned with the higher power associated with PV overgeneration events.

This result shows the trade-off between power and energy for the two applications. For provision of peaking capacity, the long peaks result in energy limits that are better suited for longer durations of storage. But for time-shifting, particularly in high PV scenarios, storage may be power limited. With sufficiently high value of time-shifting, this could justify the additional power-related costs associated with the shorter-duration storage.

As a result, it is possible that shorter-duration storage may still be deployed in Phase 3 to capture the high-power curtailment events in the high-solar scenario. Alternatively, longer-duration storage is potentially more suited to capturing curtailed energy in high-wind scenarios that do not feature high-power, short-duration curtailment events (37). Longer-duration storage can provide additional value beyond system capacity and energy time-shifting. An example is transmission deferral and congestion management. This application uses storage as a partial alternative to transmission upgrades. This service can be provided by shorter-duration storage, such as the battery peaking plants deployed in Phase 2, but longer-duration storage provides even greater flexibility to avoid upgrades. Storage can also improve utilization of transmission for remote VRE resources (38). Some of the highest-quality wind resources in the United States are in more-remote locations that might require dedicated new long-distance lines to high-population load centers. Utilization of these transmission lines will be limited by the capacity factor of the wind resource (increasing costs per unit of delivered energy). Because wind generation is often anticorrelated with load on a diurnal basis, storage can be used to increase transmission utilization (increasing the amount of energy that can be delivered per unit of transmission capacity), and it can provide system capacity and time-shifting.[29]



a) VRE supply and net load during two spring days



b) Residual curtailment after Phase 2 storage deployments

Figure 15. Availability of curtailed energy during a spring period showing length of curtailment events

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[29] Transmission deferral is an example of an application that can be partially additive ("stacked") with other services, but careful analysis is required because this application inherently limits the flexibility of the storage device to charge and discharge independently of transmission constraints.

Because of the uncertainties about energy storage value in the evolving power grid, determining the cost requirements needed to reach cost-competitive storage in Phase 3 is difficult. However, several technologies have the potential to achieve the costs reductions required for competitive deployment in Phase 3. These include batteries with lower-cost electrolyte materials, and a variety of thermal storage technologies and mechanical-based storage technologies, compressed-air energy storage, liquid air energy storage, and novel gravity-based technologies (7, 28). Next-generation pumped storage could also be cost-competitive as new technologies could reduce costs and improve performance (4). This technology includes deployment of closed-loop pumped storage plants that reduce siting constraints and permitting times, while new pump/turbine systems can provide higher efficiency and faster response (6). In addition to new pumped storage capacity, upgrades at existing sites could add more power capacity, improved efficiency (resulting in additional storage capacity), and more flexible operation.

Limits to Phase 3: Flattened Loads and the Impact of Seasonal Mismatch

The opportunities for diurnal storage technologies of 12 hours or less (i.e., in both Phase 2 and Phase 3) is very large, with upper bounds depending on a number of factors. Specific technologies might have technical or physical limits, such as geological conditions needed for both PSH and compressed-air energy storage. However, the ultimate limits to Phase 3 are economic in nature and are driven by both the cost reductions of storage and the declining value of storage. The declining value is a function of deployment, which is similar to that occurring in Phase 2, and it results from very long net-load peaks that can occur with significant storage deployment.

Figure 16 illustrates a challenge of continued storage deployment, even assuming much longer storage durations. It simulates a future in the ERCOT grid assuming 80% of its annual energy is derived from RE (36% PV, 42% wind, and 2% nonvariable RE). Storage is deployed with an installed total capacity equal to about 45% of the annual peak and across a mix of durations from 4 to 12 hours, and a system-wide average of about 10 hours.[30] The system has thermal capacity with a capacity equal to about 33% of the annual peak, which provides the remaining 20% of annual demand, including both periods of peak demand, or low RE output. Figure 16a shows the limits to storage providing capacity value as it illustrates a two-day period in the late summer with the annual peak demand. The combination of peak load reduction and storage charging produces a nearly flat net load for more than 80 hours. This means that additional storage will be unable to reduce the net load, substantially reducing its value to the system.

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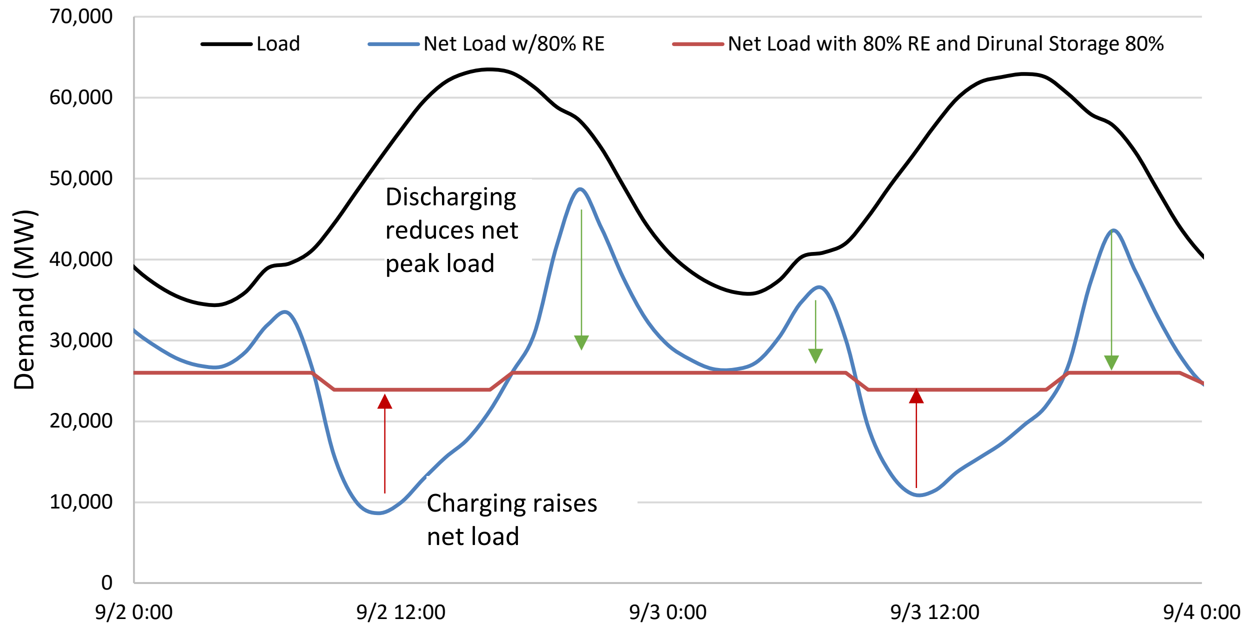
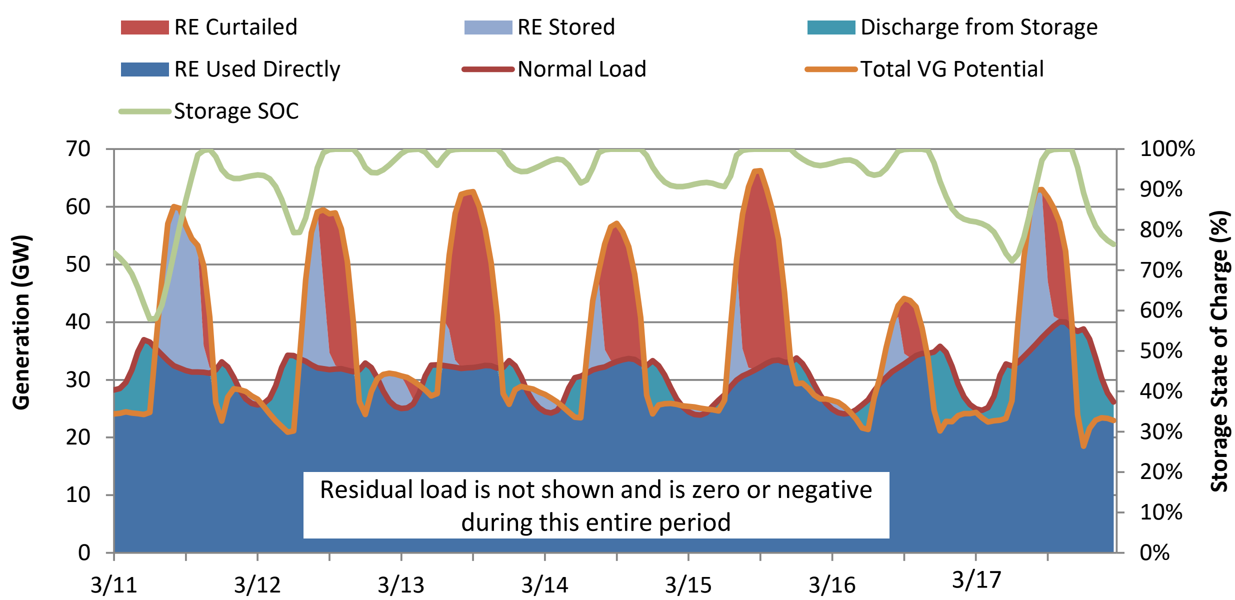
[30] This simulation uses 2013 load data with an annual peak of 67 GW.



a) Decline in capacity value due to a flattened net load



b) Decline in time-shifting value due to zero net load.

Figure 16. Simulated flattened loads in ERCOT at 80% RE

Figure 16b shows how the energy time-shifting value is limited at these levels of storage deployment. It shows the same scenario, but during a spring week with lower demand and higher VRE output than in the summer period in Figure 16a. During this spring week we have met 100% of the demand with RE, and much of the RE generation is curtailed, as the storage is completely full during periods of overgeneration. In fact, at 80% RE, there is no net load during the 31-day period from March 3 to April 4. This means any additional storage will have no time-shifting value during the entire period.

The interdependence of storage and VRE deployment creates a deployment opportunity curve for Phase 3 services that is similar in nature to that for capacity in Phase 2 (Figure 12). An example for capacity is provided in Figure 17, which shows an estimate national potential for longer-duration storage deployment with high levels of capacity credit (meaning the net load peak is less than 12 hours long) as a function of overall RE deployment.[31]

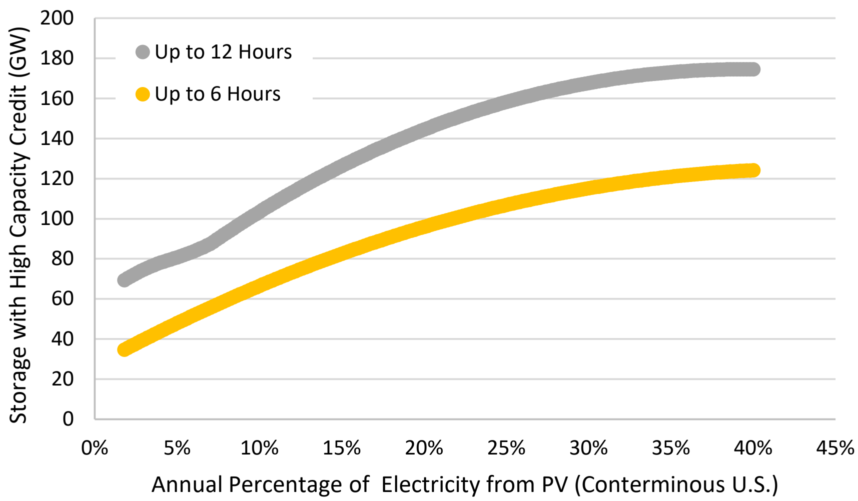


Figure 17. National opportunities for long-duration (up to 12-hour) storage providing capacity services in Phase 3

Overall, at higher levels of VRE deployment, cost-effective storage with up to 12 hours of duration creates more than 50 GW of potential for capacity-related services, but Figure 17 does not include the considerable addition (50+ GW) of opportunities for energy time-shifting and potentially transmission applications (23).

It should be noted that scenarios that explore the limits of Phase 3 often consider VRE contributions that exceed 50% on an annual basis. At these levels, the seasonal mismatch of RE supply and normal demand may require even longer-duration or seasonal storage technologies to continue further RE deployment. Such a transition represents a final phase in both storage deployment and power system decarbonization.

[31] Figure 17 was generated using the same model and data used to generate Figure 12 (35), but extended the analysis to 12 hours. These numbers are cumulative, and represent the addition of multiple durations, so the average duration across the entire deployment is considerably less. Wind does not show a significant diurnal trend that changes the ability of storage to provide firm capacity (35).

7 Phase 4: The End Game—Multiday to Seasonal Storage

Given the long time horizon associated with Phases 2 and 3, the transition to Phase 4 is highly conjectural. Studies to date have not identified a hard technical or economic limit to RE deployment with only diurnal storage, but have also found that approaching 100% RE, the seasonal mismatch of supply and demand leads to significant challenges(39, 40). This creates a potential opportunity for storage with more than 12 hours of duration, possibly extending to seasonal storage.

Alternatively, some transitions to longer-duration storage technologies might not inherently be tied to very high RE scenarios. Our four phases framework assumes most storage technologies deployed in the coming decades will continue to have a significant cost associated with duration. This cost drives the transition from shorter to longer durations, with longer durations only being deployed when the opportunities for shorter duration are largely saturated. However, many of the very long-duration storage technologies under development have very low duration-related costs. Technology breakthroughs, or dramatic cost reductions associated with deployment at scale could introduce storage with close to zero costs associated with duration and could thus result in much earlier deployment and overlap with previous phases.

Barring dramatic, near-term cost reductions, however, we expect the primary driver of very long-duration storage to be the seasonal mismatch of VRE resource supply and normal demand.

Characterizing Seasonal Storage

The decreasing utilization of both VRE and diurnal storage—and the associated increasing costs—drives the motivation for seasonal storage or other resources to further decarbonize the electric sector. The basic concept of seasonal storage is to shift the otherwise curtailed RE available in the spring to periods of higher demand or lower RE availability. Figure 18 illustrates a scenario of a 98% RE system in ERCOT, demonstrating the role of seasonal storage to shift springtime RE generation to the summer.[32]

[32] The simulation uses the same data and tools as used for Figures 2 and 3, but assumes 47% from wind, 47% from PV, 3% from hydro and other dispatchable renewables and 3% from thermal capacity.

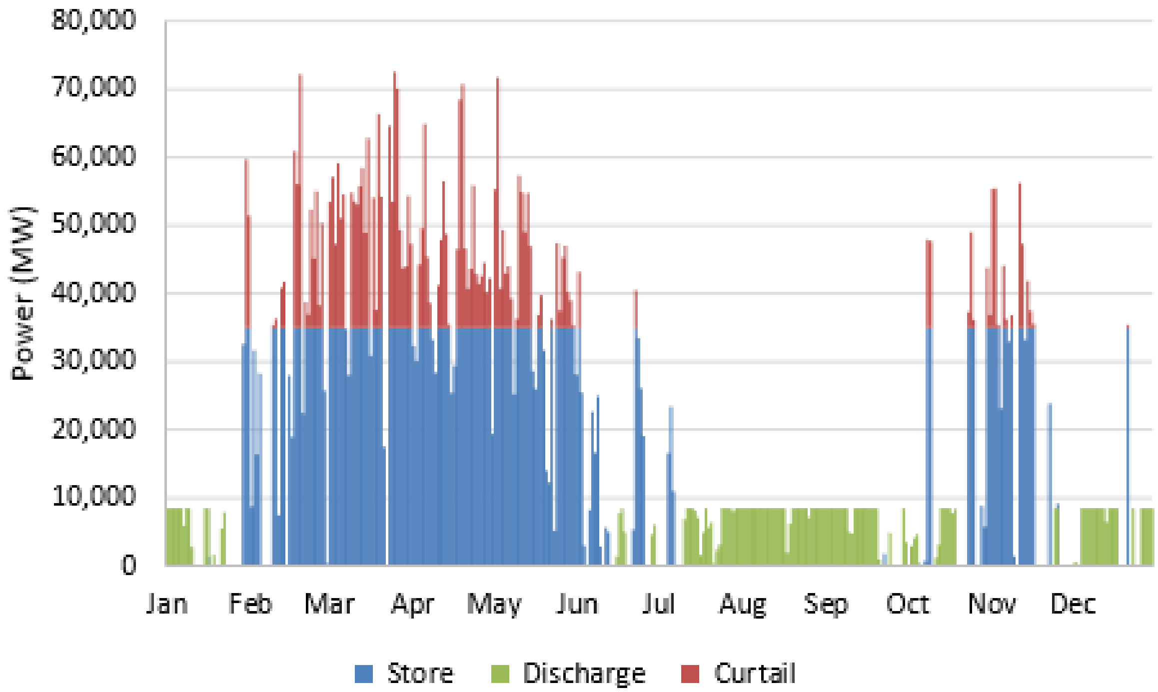


Figure 18. Chronological results of seasonal storage in a 98% RE scenario

A major outstanding question of scenarios such as that shown in Figure 18 is when or whether seasonal storage will become cost-competitive with other approaches, including low-carbon, non-RE generation.

Several storage technologies potentially offer multiday to seasonal duration, and they often use geologic storage given the large volumes required. These technologies include compressed-air and hydroelectric storage, which are typically considered diurnal technologies but have the potential for much longer durations depending on local geological conditions. Many concepts for seasonal (or beyond) storage involve the production of a liquid or gas fuel, which is typically envisioned to start with the production of hydrogen via electrolysis of water. This hydrogen then is either stored directly or undergoes additional processes to convert it to a more easily storable and transportable liquid or gas fuel. This option includes the possible production of hydrocarbon fuels using carbon dioxide produced either from fossil fuel combustion or via direct air capture. Underground storage of hydrogen, methane, or other fuels allows for storage capacity measured in months or years, and largely decouples the power- and energy-related components.

These processes are often considered to be part of a larger economy-wide transition in which storable low-carbon fuels are used for transportation and industry. This could include transportation subsectors that are difficult to electrify, such as long-haul freight, aviation, and shipping, and industrial processes including metals and cement production and bulk chemicals (41). In the electric sector, the process allows for the use of off-season renewable production (largely in the spring) to generate the storable fuel, which can be used at a later time of high demand or low renewable production.

The timing of a transition from Phase 3 to Phase 4 depends on multiple factors. The power system is not anticipated to have a significant need for seasonal storage until deployment of VRE resources greatly increase, particularly as there are plenty of opportunities for diurnal shifting using Phase 2 and Phase 3 technologies. Phase 4 could occur much earlier if there were some combination of limited advancement of Phase 3 technologies and improvements in Phase 4 technologies. For example, breakthroughs in fuel cell technologies could create accelerated demand for hydrogen in transport or electricity peaking applications even before large amounts of surplus renewable generation become available.

Alternatively, it is possible that Phase 4 energy storage technologies are deployed in a more limited fashion, or even never deployed at scale in the electric sector. Continued cost declines in VRE along with diurnal storage could allow for continued economic deployment with higher levels of curtailment. This VRE overbuild concept allows for even greater decarbonization levels without the need for seasonal storage, particularly if the storage technologies are accompanied by alternative low-carbon technologies—including fossil carbon capture and storage (CCS), direct air capture/CCS, biofuels (potentially with CCS), nuclear, or advanced demand response—that better align RE supply with demand (42–44).

Furthermore, analysis of seasonal storage technologies is complicated because they are, by their nature, very different from diurnal storage technologies. Underground storage can produce extremely low energy component costs, and as a result, the ability to store weeks or months of energy can produce artificially low overall costs when measured only by duration. A direct comparison is also complicated because many seasonal storage technologies (particularly those that involve fuel production) have much lower round-trip efficiencies than many diurnal storage technologies. However, the biggest challenge in comparing of many seasonal storage technologies and alternatives lies in the potential shared use of infrastructure to produce fuels for a variety of end uses beyond electricity. It is possible to envision costs of low-carbon fuel production infrastructure being largely paid for by other industries, with electricity use being a minor contributor and even being able to leverage existing assets such as legacy combustion turbines, which could accelerate deployment of Phase 4 technologies.

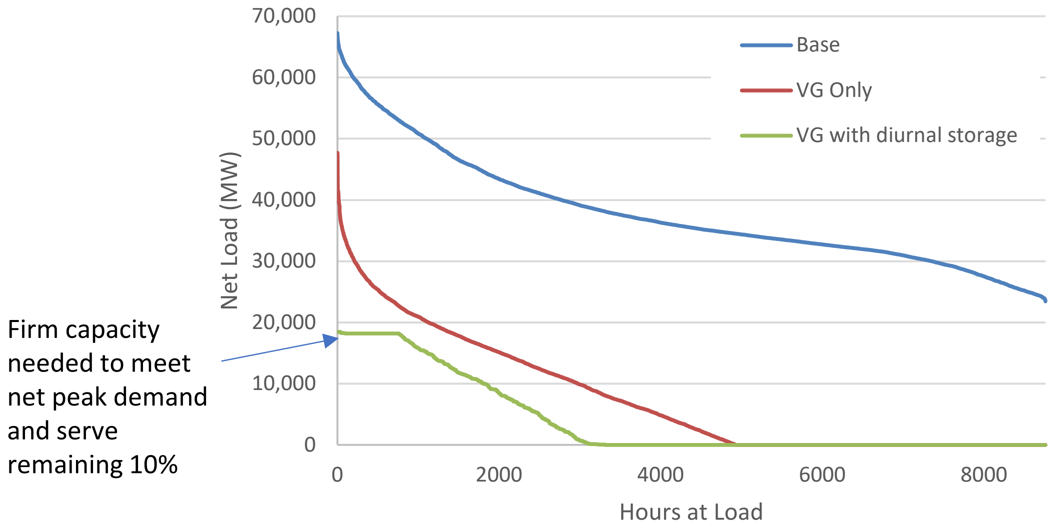
Opportunities for Seasonal Storage

Ultimately, answers to questions about both the transition to Phase 4 and the potential size of Phase 4 lie in the relative competitiveness and the declining costs for the suite of low-carbon technologies that could address the seasonal mismatch problem.

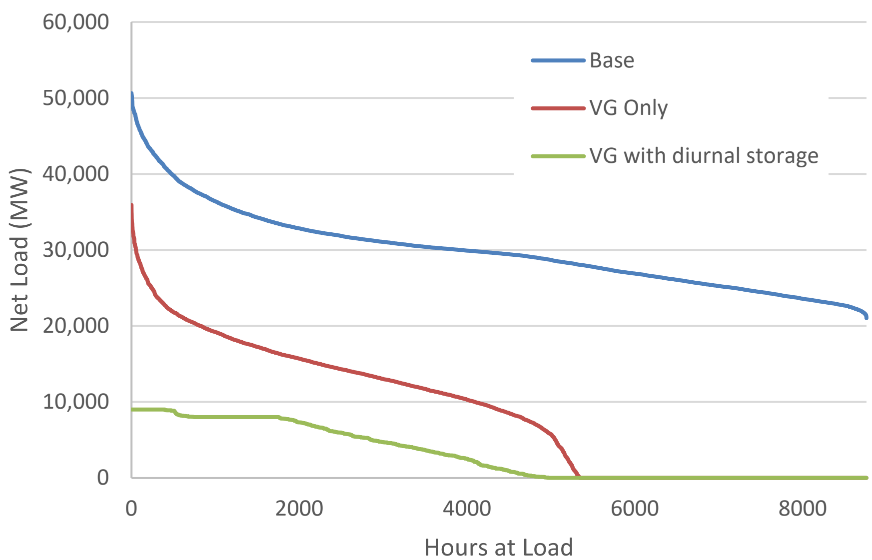
Despite these uncertainties, the potential opportunities for cost-competitive seasonal storage is large. Under scenarios where even 90% of electricity demand is met by RE plus diurnal shifting technologies, a large amount of physical generation capacity is still needed to meet the remaining 10%, as illustrated in Figure 19. Figure 19a show a load duration curve for a 90% RE scenario in ERCOT, while Figure 19b illustrates a 90% RE scenario in California.[33] In the ERCOT case, capacity providing the last 10% of the annual demand requires about 35% of the capacity, meaning that even at 90% RE, nearly 20 GW of additional capacity is needed to meet peak demand. In California, a proportionally smaller amount of additional capacity (9 GW, or 18% of the total) is needed at 90% RE, largely because of the significant contribution of RE resources

[33] The assumed contribution from RE in ERCOT is 41% PV, 46% wind, and 3% nonvariable RE. For California, the mix is 50% PV, 21% wind, and 19% nonvariable RE

with high capacity credit, including hydro and geothermal, along with the greater contribution of longer-duration pumped storage.



(a) ERCOT



(b) California

Figure 19. Residual load duration curves at 90% RE showing the need for significant firm capacity

We applied this approach to the entire United States in a set of scenarios where 80%–90% of the electricity demand in the conterminous United States is provided by various combinations of RE resources and diurnal storage.[34] We measured the residual peak demand in each region and aggregated the results. The results shown in Figure 20 provide the residual capacity requirements that would need to be met by some combination of resources with high capacity credit that could include seasonal storage.

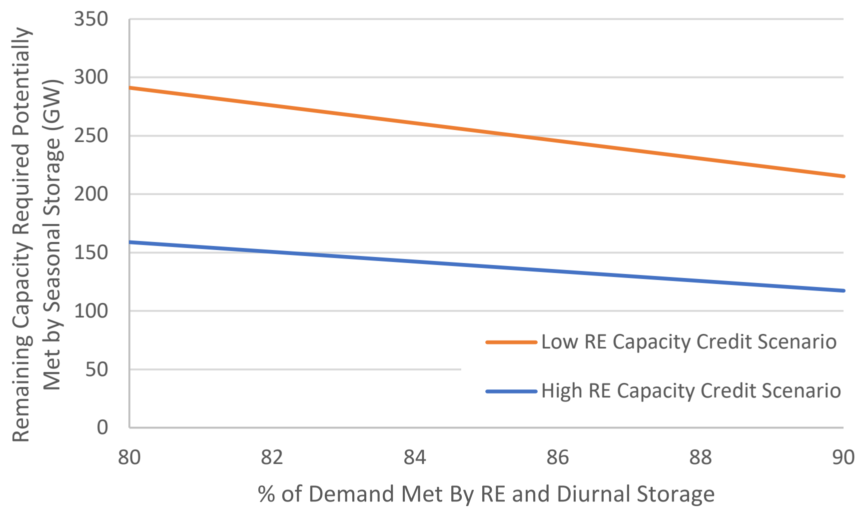


Figure 20. Bounding the size of Phase 4 by estimating the national residual capacity requirements under 80%–90% RE scenarios

[34] This represents the results of 2,000 combinations of wind, solar and diurnal storage, along with other RE resources, allowing for some geothermal and hydroelectric development in addition to the current deployments.

8 Discussion and Conclusions

The four phases conceptual framework introduced in this work is a simplification of a more complicated evolution of the stationary energy storage industry and the power system as a whole. However, we believe it is a useful framework to consider the role of different storage technologies, and particularly the importance of duration that will drive adoption in each phase.

Though we acknowledge significant uncertainties, particularly in later phases, Table 4 summaries our four phases framework with estimates of parameters associated with each phase. The premise of the table—and of this work as a whole—is that the value of storage declines incrementally as a function of duration for all grid services. Assuming the cost of most storage technologies increases as a function of duration, there is a strong economic case for deployments following a natural progression from shorter to longer duration. While phases will likely have considerable overlap, transition points between phases will largely be driven by declining value of specific services and associated durations, along with continued cost declines of various storage technologies.

Table 4. Summary of the Four Phase Conceptual Framework

Phase	Primary Services	National Deployment Potential (Capacity) in Each Phase	Duration	Response Speed
Deployment prior to 2010	Peaking capacity, energy time-shifting and operating reserves	23 GW of PSH	Mostly 8–12 hr	Varies
1	Operating reserves	<30 GW	<1 hr	Milliseconds to seconds
2	Battery peaking capacity	40–100 GW, strongly linked to PV deployment	2–6 hr	Minutes
3	Diurnal capacity and energy time-shifting	100+ GW. Depends on both on Phase 2 and deployment of VRE resources	4–12 hr	Minutes
4	Multiday to seasonal capacity and energy time-shifting	Zero to more than 250 GW	>12 hr	Minutes

The four phases framework points to the need for appropriate expectations about factors such as the value of very fast responding energy storage devices. With the exception of frequency response and frequency regulation services, nearly all grid services can be met with devices that can ramp in the minute-to-hour time frame, and faster response is not needed to provide these services. In addition, the market for the very fast response needed to provide frequency response and frequency regulation services is inherently limited, and growth in VRE deployment will likely have limited impact on the overall size of the fast response markets.

The key opportunity for storage beyond the quickly saturating operating reserves markets is the vast need for capacity that can be available during peak demand periods, starting with the roughly 4-hour long summer peaks experienced in much of the United States. This transitions to longer durations because of the simple geometry of how storage flattens load patterns, which is offset by increased VRE deployment, with PV deployment appearing to be the strongest factor behind this opportunity. Beyond this diurnal opportunity lies an uncertain scenario of deep decarbonization that potentially involves renewably fueled generators associated with multiday and seasonal storage with deployments that could also be measured in hundreds of gigawatts. This phase is also associated with deployment of technologies that enable multi-sector decarbonization via fuels production.

Of course, disruptive technology or market pathways could alter the vision we present here. Though we do not explicitly consider behind-the-meter or distribution-sited storage, we would anticipate a similar pattern of deployment, particularly if tariffs reflect the fundamental costs and values associated with the generation and delivery of reliable electricity service. Alternative pathways that potentially compete with storage could include demand response, perhaps including ubiquitous real-time pricing or other mechanisms that provide intelligent appliances and devices the ability to match demand and supply to minimize costs. Vehicle electrification represents a significant uncertainty in terms of controlled charging and even vehicle-to-grid technologies. Alternatively, the use of DC fast charging could motivate the need for additional stationary storage, particularly in areas of significant transmission congestion or other load pockets. Additionally, if storage technologies evolve such that long-duration storage can be built at the same or lower cost than shorter-duration storage (or are developed for cross-sector applications), the phases discussed here might unfold differently.

The large number of technology options available for balancing supply and demand also points to additional analytic needs for utilities and stakeholders to consider optimal least-cost portfolios. Traditional planning methods may need to be reconsidered with the impact of VRE and storage resources on traditional metrics such as planning reserve margin. New planning approaches may be needed to evaluate the ability of energy storage to provide reliable service while helping achieve regional climate goals at minimum cost.

In summary, our framework of four future phases of energy storage deployment can inform our understanding of the emerging and modeled energy future that may rely on significant new options, markets, and value in combination with variable renewable energy. Many of the concepts and themes we introduce in this work will be examined more fully in other parts of the Storage Futures Study

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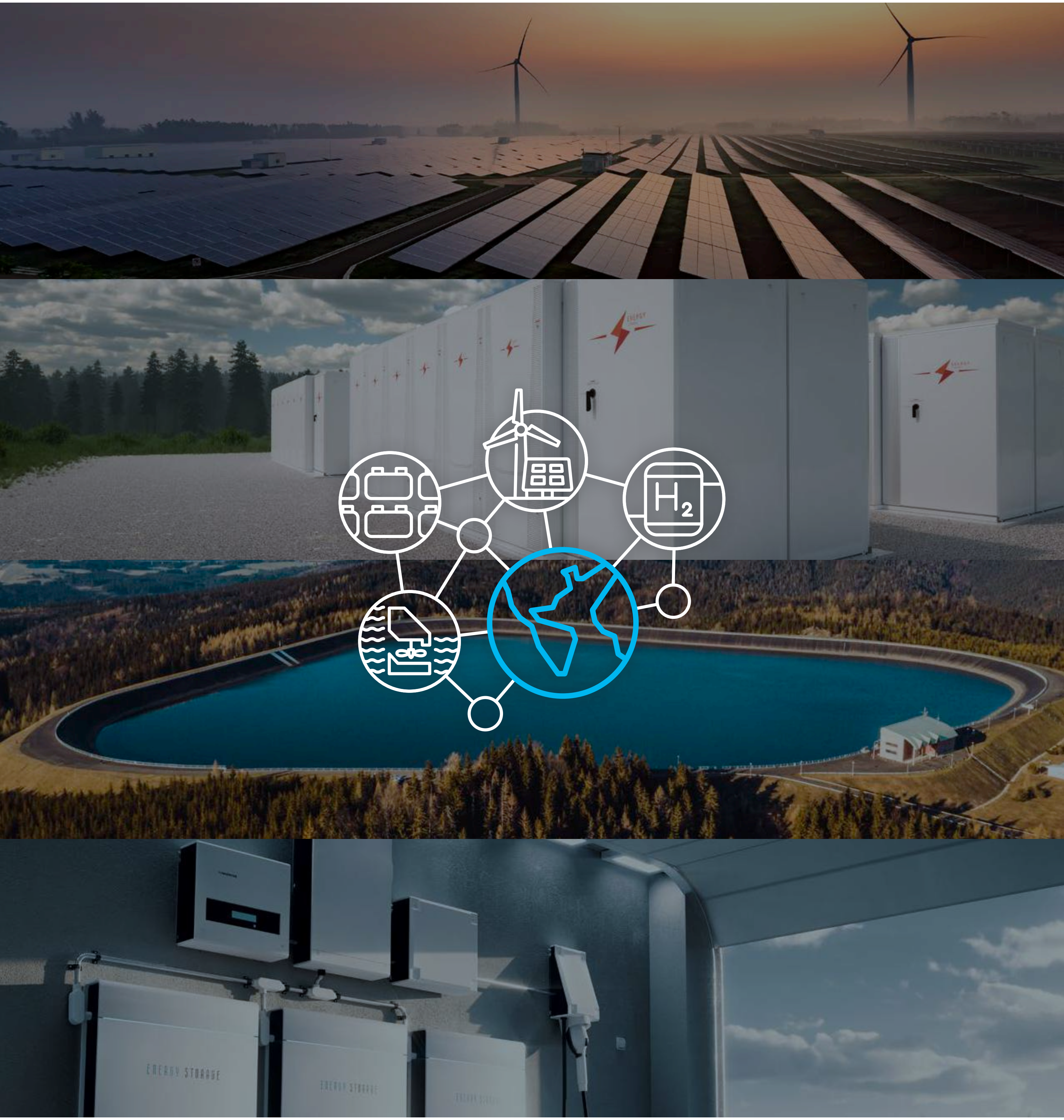

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